PRE-DECISIONAL REPORT
NEW TURBINES ADDITION STUDY
LIBBY DAM, MONTANA

EXECUTIVE SUMMARY

This report presents the findings of a preliminary study of the feasibility and cost of using available parts to install, commission, and operate one or two additional hydroelectric generating units in the powerhouse at Libby Dam. The generating units would provide the capability to release an additional 5,000 cfs or 10,000 cfs of water to meet the requirements of the 2000 Biological Opinion with respect to the Kootenai River white sturgeon, a species listed as endangered, and thus meet the requirements of the 1974 United States Endangered Species Act.

The powerhouse at Libby Dam was constructed to house eight turbine-generator units. Four units were installed as part of the original construction. The parts for four more units were ordered and delivered to the site, but the appropriated funds were only sufficient to complete and commission one more unit (Unit 5) and to partially complete the installation of the other three turbines. The remainder of the equipment to complete the other three units has remained in storage at the site since the early 1980s. Some parts of one unit have been used to replace parts in the operating units, and a transformer was used at another U.S. Army Corps of Engineers project.

Safety considerations prevented inspection of the interiors of the water passages and of the turbine runners, and their condition is therefore unknown. The turbine parts that could be inspected, and the majority of the remaining equipment required to complete one or two units appear to be in good condition. The interiors of the water passages and the turbine runners must be inspected to determine their condition and confirm the feasibility of completing and operating the units. A protocol to safely access the interior passages would first have to be established and executed. Unless severe corrosion of the water passages, particularly the penstock, is discovered, which is considered unlikely, then it appears technically feasible to complete the installation and commissioning of one additional unit. The installation and commissioning of a second unit also appears to be feasible, but is subject to determination of the feasibility of transporting the necessary transformer to the site.

Costs were estimated for three cases: completing and commissioning one additional unit, completing and commissioning one additional unit and providing a standby transformer, and completing and commissioning two units complete with the necessary additional transformer. In view of the unknown condition of the interior of the turbine, the cost estimates include allowances for refurbishment of parts that may have deteriorated.

The technical feasibility of installing and commissioning the additional units not withstanding, the existing and any additional units can only be operated to generate electricity, and hence release the required flow if there is sufficient transmission line capacity and demand (load) to accommodate the output. There are currently both regional and local transmission capacity constraints that limit the output from the existing five units from time to time, and these constraints would preclude the transmission of the additional generation from six or seven units that would be required to release the flows necessary to meet the 2000 Biological Opinion. The improvements and approximate associated costs to overcome these constraints were identified. The minimum cost to

upgrade the transmission system is more than 10 times the cost of installing the generating units. The time frame for completing the transmission upgrades is uncertain, but is probably at least four years away. Consequently, it is concluded that it is not currently feasible to release the additional flows required by the 2000 Biological Opinion by installing additional generating units.

Means of releasing the additional flows without generation of electricity (non-generation alternatives) were also considered. The non-generation alternative concept considered most likely to be feasible would involve the removal of the turbine runners, head covers and wicket gates and the installation of three pressure-reducing valves in each of the three non-commissioned units. The concept would only provide about half of the additional releases required by the 2000 Biological Opinion. In addition, although pressure-reducing valves are proven technology, their use in this application would be unprecedented. Several years of investigations and tests would, therefore, be required to confirm the feasibility, develop an appropriate design, and complete the fabrication and installation. Consequently, it is concluded that pressure-reducing valves do not currently provide a feasible alternative means of releasing the additional flows required by the 2000 Biological Opinion.

The spillway and/or sluices provide alternative means of releasing water from Libby Dam. However, the use of the spillway and/or sluices is the subject of a separate study (RPA 8.2.a.3), and was, therefore, excluded from the scope of this report.

The results of the study are summarized in the following table.

SUMMARY OF ALTERNATIVES

ALTERNATIVE	FLOW (cfs)	CAPITAL COST[3] (2002$)	O AND M COST (2002$)	MANDATORY TRANSMISSION IMPROVEMENTS	TRANSMISSION COSTS[2] COMPONENT (2002$)	TRANSMISSION COSTS[2] TOTAL (2002$)	COMMENTS
One additional unit	5,000	5.8 M	350,000	Libby-Noxon Line 2, AND	25 M[1]		Provides half of 2000 BiOp flow
				West of Hatwai Additions	115 M - 120 M		Increases operational flexibility
				Subtotal of common improvements	140 M - 145 M		Increases reliability of five units
				PLUS EITHER			Intermittent additional generation
				West of Noxon Reinforcement Phases 1 and 2	126.4 M	266.4 M - 271.4 M	Internal unit inspection required
				OR			
				Noxon - Benewah Reinforcement	40 M[1]	180 M - 185 M	
				OR			
				Noxon - Shoshone - Reinforcement	35 M[1]	175 M - 180 M	
One additional unit plus spare transformer	5,000	9.4 M	350,000	Same as above	Same as above	266.4 M - 271.4 M 180 M - 185 M 175 M - 180 M	Same as above plus Increased electrical reliability Requires transportation feasibility study
Two units plus required additional transformer	10000	13.9 M	700,000	Same as above	Same as above	266.4 M - 271.4 M 180 M - 185 M 175 M - 180 M	Provides full 2000 BiOp flow Increases operational flexibility Increases reliability of five and six units Intermittent additional generation Internal unit inspection required Requires transportation feasibility study
Installing three pressure reducing valves in each spare turbine spiral case.	5,300	7 M-8 M[1]	150,000	None required	None	None	Feasibility needs to be established Provides half of 2000 BiOp flow Preserves existing parts as spares Does not require transmission upgrades Could permit return to generation in future
Spillway/sluices	TBD	TBD	TBD	None required	None	None	Detailed study required

Notes:

(1) Cost are "ballpark" estimates without contingencies.
(2) Cost does not include transmission capacity acquisition incurred on an annual basis. No annual access, wheeling, or tariff charges.
(3) Does not include capitalization cost or IDC.

1.0 INTRODUCTION

1.1 Objective

This report presents the findings of a preliminary study of the feasibility and cost of using available parts to install, commission, and operate one or two additional hydroelectric generating units in the powerhouse at Libby Dam. The generating units would provide the capability to release an additional 5,000 cfs or 10,000 cfs of water to meet the requirements of the 2000 Biological Opinion, and thus the requirements of the 1974 United States Endangered Species Act (ESA).

1.2 Terms of Reference

The study was commissioned by the U.S. Army Corps of Engineers (Corps), Seattle District, and was performed under Contract No. DACA67-00-D-2007-0035.

1.3 Background

The Kootenai River white sturgeon live in Canada's Kootenay Lake, but travel upstream into the United States to spawn(1). In 1994, the Kootenai River white sturgeon was listed as endangered by the U.S. Fish and Wildlife Service (USFWS) under the terms of the 1974 United States ESA. The USFWS cited Libby Dam as the most significant factor in the species' decline. The endangered listing and the designation of critical Kootenai River white sturgeon habitat downstream of Libby Dam has created the need to evaluate changing the operations at Libby Dam in an effort to achieve successful sturgeon recruitment.

The 2000 Biological Opinion (2000 BiOp) proposed a list of actions to be implemented by the U.S. federal dam operators and the Federal Columbia River Power System (FCRPS) to effect protection of ESA listed fish. The 2000 BiOp includes a plan to replicate a portion of the Kootenai River's annual hydrograph before the construction of Libby Dam. The expectation is that creating flows and temperatures approximating preconstruction conditions will stimulate and support successful white sturgeon recruitment.

The desired flow capacity from Libby Dam under the 2000 BiOp is 35,000 cfs. The current powerhouse capacity is about 25,000 cfs. Consequently, the dam cannot currently pass the desired flow without spilling about 10,000 cfs. Spilling is believed to be potentially unacceptable because it would result in violation of the Montana State total dissolved gas (TDG) standard of 110 percent saturation, and potentially harm other resident ESA listed fish (Bull Trout) or potentially listed fish (Burbot) in the waters immediately downstream of Libby Dam.

To comply with the 2000 BiOp, and thus with the ESA, a means must be found to increase releases either through the powerhouse or by some other method that does not involve use of the existing spillway or sluices.

The powerhouse at Libby Dam was designed and constructed to house eight Francis-type, turbine-generator units. Four units were installed in the initial development completed in 1975, and four more units were planned to be installed in conjunction with the construction of a reregulating dam some distance downstream (Libby Additional Units and Reregulating Dam project). In 1978, the U.S. District Court in Montana enjoined the construction of the Libby Additional Units and Reregulating

Dam project citing lack of congressional authorization and failure to provide a satisfactory environmental impact statement. The Ninth Circuit Court of Appeals upheld the District Court injunction of the reregulating dam, but not of the additional units. This court ruled that the reregulating dam had not been authorized by Congress, but that the installation of the additional units (Units 5 to 8) had been authorized. Congress appropriated sufficient funds through fiscal year 1981 to complete purchase and delivery of the equipment for Units 5 to 8, but only allowed sufficient funds in subsequent fiscal years to fully complete and commission Unit 5. The funds were also apparently sufficient to complete the installation of the principal components of the turbines for Units 6 to 8. The remainder of the equipment was delivered to the project and has been in storage in the powerhouse and in the site warehouse since then. Some equipment, primarily a transformer, has been used at another Corps of Engineers power project.

Barring other constraints, completion and commissioning of one or two of the additional units would enable the release of an additional 5,000 cfs or 10,000 cfs through the powerhouse and meet the requirements of the 2000 BiOp.

1.4 Scope of Work

The scope of work consisted of the following.

- *A site visit and visual inspection of the three incomplete turbine-generator bays, to document the current conditions and salvageable equipment;*
- *A brief hands-on inventory of major generating and turbine components available at Libby Dam to construct one or two additional turbine-generator units;*
- *Assessment of the feasibility and cost of completing and commissioning one or two additional units;*
- *Estimation of the approximate annual operation and maintenance costs of one or two additional units;*
- *Identification of transformer and transmission constraints that would limit operation of one or two additional units, and program-level strategy and costs to overcome the constraints;*
- *Estimation of the annual power production and value from the additional one or two units, assuming that they would only be used when the FCRPS turbines are at capacity;*
- *Identification of the potential benefits to Libby Dam operations and reliability of having one or two units available for standby power, together with any additional transformer needs and budget-level costs;*
- *Consideration of non-generation alternatives for providing the additional releases required by the BiOp; and*
- *Preparation of a report on the findings of the study.*

2.0 SITE VISIT

2.1 General

The site visit was conducted between 4 and 6 June 2002. The visit commenced with an inaugural project meeting with station staff to review the scope of work, the history of the project, and discuss pertinent issues that may be constraints on the alternatives to be considered.

The remainder of the visit was spent inspecting the existing facilities, particularly the partially installed units, and the parts stored in the powerhouse and warehouse, and examining inventories, documents, and drawings, and comparing them with observations in and around the powerhouse. Additional discussions were held with station staff during the course of the visit.

A detailed account of the site visit is included in Appendix B. A generator parts checklist was used during the inspection and is included in Appendix C. A selection of photographs is included in Appendix D. The following sections describe the principle findings.

2.2 Existing Installation

The dam and powerhouse were constructed and Units 1 to 4 were installed between 1966 and 1975. Unit 5 was completed and put into service in 1985.

The powerhouse is completely enclosed with normal building services of light, heat, and ventilation available throughout.

The turbines in Units 6, 7, and 8 are almost completely installed, to the point of being "shaft free," which is the customary description of the hand-over condition for the start of generator installation (Photos 1 and 2).

The generators and other electrical equipment for Units 6, 7, and 8 are mostly stored in the powerhouse, within the concrete generator housings, on the Elevation 2131.5 level between the units (Photos 3 and 4), and along the upstream gallery under the transformer deck (Photos 5 and 6). Some parts are stored in a nearby warehouse on the site.

The five existing generators are connected to two outgoing transmission lines through three transformers. Units 1 and 2 are connected to transmission line No. 1 through Transformer T1. Units 3 and 4 are connected to transmission line No. 2 through Transformer T2. Unit 5 is also connected to transmission line No. 2, but through Transformer T3. Transformers T2 and T3 are connected to transmission line No. 2 by an outdoor bus system suspended above the transformer deck. The transmission line connections differ from the original design.

Penstocks 6, 7, and 8 are each closed by a hemispherical bulkhead at the upstream end. These were not inspected, but the scope of work to remove them will be the same as included in the contract for Unit 5 and the cost can, therefore, be estimated.

2.3 Inventory

Inventory records of stored equipment from the station files were reviewed and found to be comprehensive and well organized. Boxes and crates were catalogued and labeled in the inventory file binder by unit, box number, and manufacturer's equipment coding and drawing reference. This identification system allows selection of boxes from storage based on the part numbers shown on the manufacturer's assembly drawings. A location plan was also prepared, but observations in the powerhouse indicate that many storage crates have been relocated and the plan is, therefore, no longer accurate. The current status and location of the inventory should be determined and the location plan updated either prior to or as part of resumption of installation.

From a review of the inventory record, all of the major components for the three units are accounted for. The turbines are already installed and are not, therefore, included in the list of stored equipment.

2.4 Condition Assessment

Turbines 6, 7, and 8

Almost all of the turbine components are installed in Units 6, 7, and 8, and what could be seen were in good condition. When the project was mothballed in 1985, measures were taken to protect components and surfaces from deterioration. Some exceptions were noted where parts have been removed or were insufficiently protected for storage.

The turbine bearing and shaft seal from Unit 6 have been removed and used in the overhaul of an operating unit. The surface condition of the bearing and shaft seal areas on the shaft and in the headcover were good. Some small components from Unit 6 have also been used to maintain the operating units.

The turbine runners (water wheels) or the inside of the water passages were not inspected because of safety considerations due to the uncertainty of the water levels within the units.

A water level sight tube is installed at the draft tube door of Unit 7 and no water was observed in the tube. The drain valves in the penstock/spiral case stubs were opened and apart from a couple of drips, presumably from condensation, no water was evident. The draft tubes are closed with concrete stop logs that were sealed when they were installed. The draft tube drains are open to the station sump.

Based on these observations, it appears that the water levels in the draft tubes are probably well below the runners. There are no records of internal inspections, so the condition of the runners and other water passage surfaces is not known. The spiral cases were painted before the project was mothballed, and the turbine embedded components are normally well painted. The water passage surfaces may, therefore, be in good condition, and able to be used without modification or repair. This includes the penstocks, spiral casing, stayring, wicket gates, bottom ring, discharge ring, and draft tube liner.

Given the length of time the units have been in mothballed condition and the uncertainty of the water levels and degree of humidity within the water passages, it *is essential that an internal inspection be made of the runner from above and below.*

The turbine guide bearing and shaft seal assemblies must be removed for inspection of the internal and running surfaces. Shaft coupling bolts to the runner should be verified by torque or by bolt stretch measurement and compared to the original installation records.

A visual examination should be made into the runner seals and crown and band spaces using fiber optic boroscopes to get into small spaces.

In view of the unknown condition of the interior water passages and the runner, allowances for refurbishment have been included in the cost estimates.

Generators 6, 7, and 8

The majority of the static components of the generators are stored in the generator pits but are not assembled. Some of the rotating parts are also stored in the pits, and the remainder are stored either in the powerhouse or in the warehouse.

The environment within the generator housing was dry and relatively clean. Although there was some construction debris and dust, the amount was considered normal for a construction site. A good wipe down and vacuuming would be required before commencing stator installation.

The generator rotor rim plates were originally stored outside during the project shutdown process and were discovered to have significant amounts of rust in 1992. Although now stored in the powerhouse, inspection confirmed that almost all of the plates are rusted (Photos 12 and 13). The plates would have to be refurbished or replaced. The cost estimates include replacement of the plates.

Turbine Governor Systems

The governor cabinets have been mostly assembled, but some mechanical and electrical work remains to be completed. Some of the front panel gauge and control devices are missing. A detailed examination by a Woodward installation advisor will be required to restart installation. Replacement of small missing parts and instruments may be necessary.

Electrical Cabinets and Control Panels

Unit protection relay panels appear to be in good condition, although a meter is missing from one panel. The Westinghouse static exciter cabinets also appear to be in good condition, and anti-condensation heaters were installed.

The 480 volt distribution panels and motor control centers for Units 6, 7, and 8 are in place and connected.

All installed wiring would have to be checked and traced. Additional or replacement wiring may be required.

Penstocks

The penstocks were not inspected and their internal condition is, therefore, unknown. As in the case of the turbine runner, it is essential that an internal inspection be made of the penstock. The penstocks incline upwards at a relatively steep angle (32.5°) and are unventilated. Special arrangements will, therefore, be required to safely access and inspect the interiors.

3.0 FEASIBILITY AND COST OF INSTALLING UNITS

3.1 Feasibility

The interiors of the water passages could not be inspected due to safety considerations. Consequently, the internal condition of the passages, particularly the penstocks, and the condition of the turbine runners are unknown. To establish the condition, and hence determine the feasibility of completing and operating the units, it will first be necessary to establish and execute a protocol to safely access the interior of the units and conduct an inspection. Safe access to inspect the underside of each of the turbine runners will require confirmation that the water level in each draft tube is below the level of the draft tube access door and will remain so until the completion of the inspection and the closing and resealing of the door.

To complete this preliminary assessment in the absence of an internal inspection, some assumptions and allowances have been made with respect to the internal condition. Firstly, the one condition that would preclude completion and operation of the units would be corrosion of the penstocks and other water passages sufficiently severe to render the passages incapable of withstanding the internal water pressure. Repairs would probably involve the installation of steel linings and would be prohibitively expensive. Severe corrosion requires a continuous supply of moisture and oxygen or electrolytic action. Although the interiors of the passages are probably moist, the passages are effectively sealed off from a supply of oxygen, and the projects grounding system has presumably protected the embedded parts from electrolytic action by stray currents. Consequently, in our opinion, it is unlikely that the passages have experienced severe corrosion, and an allowance for repairs has not, therefore, been included. The draft tube liner may have been more vulnerable to corrosion. However, this is not a high-pressure conduit and an allowance has been included for sandblasting and repainting.

The second condition that would involve significant additional cost, but that would not preclude completion and operation of the units, is if the corrosion of the runners is sufficiently severe to require replacement. Such severe corrosion is also unlikely. Allowances have, nevertheless, been made for dismantling the turbines, for replacing stationary and rotating seals, and for machining the running surfaces.

Subject to the completion of an internal inspection and confirmation of the satisfactory condition of the interior of the penstocks and the other water passages, completion of the installation and commissioning of one additional unit appears to be feasible.

Installing and operating a second additional unit appears also to be feasible. However, a second unit would require an additional transformer. As discussed in Section 6.1, there is currently some doubt as to the feasibility of transporting a transformer to the project site.

The feasibility of installing the units notwithstanding, there are existing transmission constraints discussed in Section 6 of this report that would currently preclude operation of the additional units except in place of the existing units.

3.2 Estimated Cost

Based on the assumptions outlined above, the estimated cost to install and commission one additional unit is $5.8 million (2002 $). The estimate assumes that the new unit would be Unit 7 and that it would be connected to the existing transformer T3 with an extended bus. Although Unit 6 is the closest to transformer T3 and would, therefore, seem the more natural choice to complete and commission, several parts of the turbine and other equipment have been used to replace parts in the existing units. Consequently, completion of Unit 6 would involve not only the dismantling of its turbine for inspection but also the partial dismantling of the turbine of Unit 7 or 8 to replace the missing parts. A detailed breakdown of the estimate is included in Appendix A.

Assuming that a transformer can be transported to the site, the provision of an additional standby transformer with installation and commissioning of one unit would increase the estimated cost to $9.4 million. A detailed breakdown of the estimate is also included in Appendix A.

Based on the foregoing assumptions with respect to water passage condition and transportation of a transformer, the estimated cost to install and commission two additional units is $13.9 million (2002 $). The estimate includes the supply and installation of a new transformer similar to the existing ones. The transformer (T4) would be installed in the existing bay originally provided for it, and Units 7 and 8 would be the natural choice to complete and commission. A detailed breakdown of the estimate is also included in Appendix A.

4.0 OPERATION AND MAINTENANCE

Plant staff indicated that each unit undergoes an annual overhaul with a four- to six-week outage. The addition of two more units to the existing five would change an average 25-week maintenance effort to 35 weeks.

Daily, weekly, and monthly maintenance cycles would similarly be increased by having to deal with two more units. Although two units represents a 40 percent increase in the number of units, the additional inspection and maintenance man-hours should not increase by this ratio.

Libby staff indicates that the current total annual cost of the existing facilities specific to hydroelectric generation is approximately $3.5 million per year.

For budgetary purposes, a 10 percent increase in regular maintenance costs would be reasonable, with the additional cost of two more five-week outages per year for the annual inspections and overhauls. Based on the current total annual cost, it is estimated that annual operating and maintenance costs would increase by approximately $350,000 per additional unit.

5.0 EVALUATION OF BENEFITS

5.1 Additional At-Site Generation

Bonneville Power Administration (BPA) has modeled the operation of the FCRPS under the 2000 BiOp and provided output from the computer model, together with a memorandum outlining the operating assumptions[4]. The system model uses a monthly time step and a 50-year period of historic inflows from 1 August 1928 to 31 July 1978. BPA advises that Libby Dam and other FCRPS projects are already being operated to meet the requirements of the 2000 BiOp within the existing project constraints. These constraints include the hydraulic capacity of the existing units in Libby powerhouse. In the opinion of BPA, any impacts on generation due to changes in reservoir operations and monthly volumes of water released from the dam to meet the requirements of the 2000 BiOp have already occurred, and are reflected in the model results.

In the opinion of BPA, additional units at Libby would not alter the monthly volumes of water released from the dam indicated in the model results. The only change would be in the magnitude of daily releases during the period from mid-May to the end of June. Consequently, apart from possible slight efficiency improvements, the additional units would not produce any more monthly generation than shown in the model results, except when the monthly release from the project exceeds the hydraulic capacity of the existing units, i.e., when the project would otherwise be forced to spill.

There are two periods of the year when releases may exceed the hydraulic capacity of the existing units, between January and March, when the reservoir level is being drawn down to provide flood control storage, and in June and July, when inflows can exceed the available storage. The additional generation that could be produced by one and two additional units was estimated by multiplying the average monthly generation shown in the model results by the ratio of the amount of spill that could be used divided by the discharge through the existing units. The results of these calculations are shown in Tables 5.1 and 5.2.

Table 5.1 shows that one additional unit could have provided additional average annual generation of approximately 3 megawatts (MW) over the 50-year simulation period. Valued at $30 per megawatt-hour (MWh), this increased generation would theoretically produce an average annual revenue of about $788,400. However, several factors reduce the actual value of the generation.

Firstly, the additional generation would have occurred intermittently. Years that would potentially produce additional revenue would have been interspersed with numerous years in which there would have been no additional revenue. For example, there would have been six years with no additional generation from 1936 to 1941, one month's additional generation in July 1942, and then five years with no additional generation from 1943 to 1947. Consequently, a present worth analysis would probably show a significantly reduced levelized benefit.

Secondly, less than half of the additional generation would occur in the period January to March, when there would probably be a reliable market for the additional generation. The remainder of the generation would occur in June and July, when there is typically an abundance of surplus hydroelectric generation in years of large flows, and consequently a significantly reduced likelihood of being *able to market the additional generation. As an example, approximately 7 percent of the long-term average annual additional generation would have been produced in one month, June 1948. Inspection of the model results at other stations in the system in June 1948 shows that spill at The Dalles would have been in excess of 270,000 cfs in that month. Consequently, there would have been no market for the additional generation.*

Table 5.2 shows that a second additional unit could have provided additional average annual generation of approximately 0.5 MW over the 50-year simulation period. Valued at $30 per MWh, this increased generation would theoretically produce an annual average revenue of about $131,400. However, the additional generation would have been even more sporadic than for the first additional unit, although a similar percentage would be produced in the marketable February period.

A previous study by the Corps[3] credited the second set of four turbines with an estimated 2.6 percent increase in efficiency. The difference was attributed in part to the probable deterioration in the efficiency of the older units due to blade wear and repair, and in part to a different stay ring design in the second set of units. Although the reasoning is sound, the difference in efficiency does not appear to have been proven by performance tests. Consequently, it has not been considered in this study. Furthermore, increasing the magnitude of releases in May and June to meet the 2000 BiOp will result in a rise in the tailwater level for all the units of about 1.5 feet or approximately an additional 0.4 percent of the gross head, which will decrease the generation of all the units by this amount. However, because an increase in efficiency would produce a definite increase in annual generation from a given discharge, the difference in efficiency should be investigated if an economic argument is to be presented to support the commissioning of additional units.

The previous study also credited the additional units with an increase in generation due to an increase in availability. However, the underlying assumption in that study was that only five units would be operated at any one time, except when there would otherwise be spill. The additional units would theoretically increase the availability and, therefore, the generation. However, review of the BPA model results indicates that Libby is operated for a substantial period of the year with only one or two units. During these periods, the other four or three units already provide redundancy, and a relatively high degree of reliability. To illustrate this point, the number of units operating in each month of the 50-year BPA simulation period was estimated, assuming a five-unit station. Based on an assumed average unit availability of 97 percent, the long-term average annual availability of the existing five-unit station was estimated to be 98.69 percent. One additional unit would increase the long-term average availability of five units by 1.27 percent, and two additional units would increase the average availability of five units by an additional 0.04 percent, bringing the availability of five units effectively to 100 percent. However, in the case of the present study, operation of up to six or seven units would be required during May and June in most years. During this period, with one additional unit, the average availability of six units would be only 83.3 percent, based on an assumed average unit availability of 97 percent. With two additional units, the average availability of six units would be 99.5 percent, but the average availability of seven units would be only 80.8 percent, based on an assumed average unit availability of 97 percent.

Consequently, although the additional units would increase the overall reliability of the station during the majority of the year, there would still be a relatively high probability of having insufficient units available to release the flows required by the 2000 BiOp. In addition, the calculations did not take into account transmission system reliability. Forced outages (failures) of the transmission system would decrease the overall availability of the station.

TABLE 5.1
FIRST UNIT ADDITIONAL GENERATION

YEAR	ADDITIONAL GENERATION (MW)												
	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	July	Annual
1929													
1930													
1931													
1932													
1933							80						6.1
1934						12							1.0
1935							55						4.2
1936													
1937													
1938													
1939													
1940													
1941													
1942												114	9.7
1943													
1944													
1945													
1946													
1947													
1948											119		9.7
1949													
1950							91						7.0
1951												50	4.2
1952													
1953												38	3.3
1954							87					113	16.2
1955												114	9.7
1956							4					37	3.5
1957													
1958													
1959							88						6.8
1960													
1961											31		2.6
1962													
1963												62	5.2
1964												25	2.1
1965							71	11					6.4
1966							90						6.9
1967							86						6.6
1968													
1969							88					45	10.6
1970													
1971											85	52	11.5
1972							67					114	14.8
1973													
1974												14	1.2
1975													
1976													
1977													
1978													
Average						0.2	16.1	0.2			4.7	15.6	3.0

TABLE 5.2
SECOND UNIT ADDITIONAL GENERATION

YEAR	ADDITIONAL GENERATION (MW)												
	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	July	Annual
1929													
1930													
1931													
1932													
1933							49						3.8
1934													
1935													
1936													
1937													
1938													
1939													
1940													
1941													
1942												12	1.0
1943													
1944													
1945													
1946													
1947													
1948											119		9.7
1949													
1950													
1951													
1952													
1953													
1954												15	1.3
1955												25	2.2
1956													
1957													
1958													
1959							22						1.7
1960													
1961													
1962													
1963													
1964													
1965							29						2.2
1966							25						1.9
1967													
1968													
1969							23						1.8
1970													
1971													
1972												2	0.1
1973													
1974													
1975													
1976													
1977													
1978													
Average							3.0				2.4	1.1	0.5

The overall conclusion of this analysis is that, barring a possible improvement in efficiency, the additional units would provide no reliable economic benefit and would require a substantial investment in upgrades to the regional and local transmission systems as discussed in Section 6.2.

5.2 Downstream Generation

In the opinion of BPA, any impacts on the generation at stations downstream of Libby as a result of the implementation of the 2000 BiOp have already occurred, and changes in the magnitude of daily flows that would occur as a result of increased hydraulic capacity at Libby would readily be accommodated within the system. Consequently, changes to the downstream benefits attributed to Libby would not be significantly altered by the additional units.

5.3 Libby Operations and Reliability

The additional units would benefit current operations and would generally improve reliability. The principal benefits would include the addition of a second station service supply from the first new unit, and increased flexibility to take units out of service for maintenance and to deal with forced outages without compromising generation during the majority of the year. The additional units would not, however, contribute increased reliability during the critical BiOp period, when all the units would need to be available. The additional units would also provide no increase in protection against forced outages due to the transmission system.

If only one additional unit is commissioned, a fourth transformer would provide redundancy and, therefore, increased reliability.

Commissioning one or two of the additional units will reduce the current availability of spare parts, although the remaining parts from Unit 6 would still be available. Consumption of the available spares to date does not appear to have been great, but the need for spares can be expected to increase with time.

6.0 POTENTIAL CONSTRAINTS ON OPERATION

6.1 Transformers

The capacities of the existing transformers T1 and T2 are fully committed to Units 1 to 4. Transformer T3 currently serves only Unit 5 and, therefore, has the capacity to accommodate the output of one additional generating unit. A second additional generating unit would require the purchase of another transformer. Ideally, the new transformer would have the same capacity as the existing transformers, to facilitate the direct connection of Units 7 and 8. The cost of such a transformer is included in the estimated cost of installing the second additional unit.

The three existing transformers were delivered to the site by rail. Since then, the middle pier of the railroad bridge across the Fisher River, approximately 3 miles downstream of the dam, has been compromised by flood waters and the bridge is no longer usable. Doubt has, therefore, been expressed as to the feasibility of delivering a new three-phase transformer to the site. A study is required to determine whether there is a highway route to the site that would permit the approximate 212-ton stripped dry weight of a three-phase transformer to be transported by a multi-axle steering low-bed trailer without exceeding the allowable loadings of bridges on the route. If a transformer with the same capacity as the existing transformers cannot be transported to the site, then a smaller transformer with sufficient capacity to accommodate one additional unit could be considered.

From a purely electrical perspective, transformation could be accomplished using three smaller single-phase transformers. However, these transformers would not fit within the existing bay provided for a fourth three-phase transformer. It is doubtful from the perspectives of safety and access that three single-phase transformers could be accommodated in the space available outside the existing bay.

6.2 Transmission Lines

General

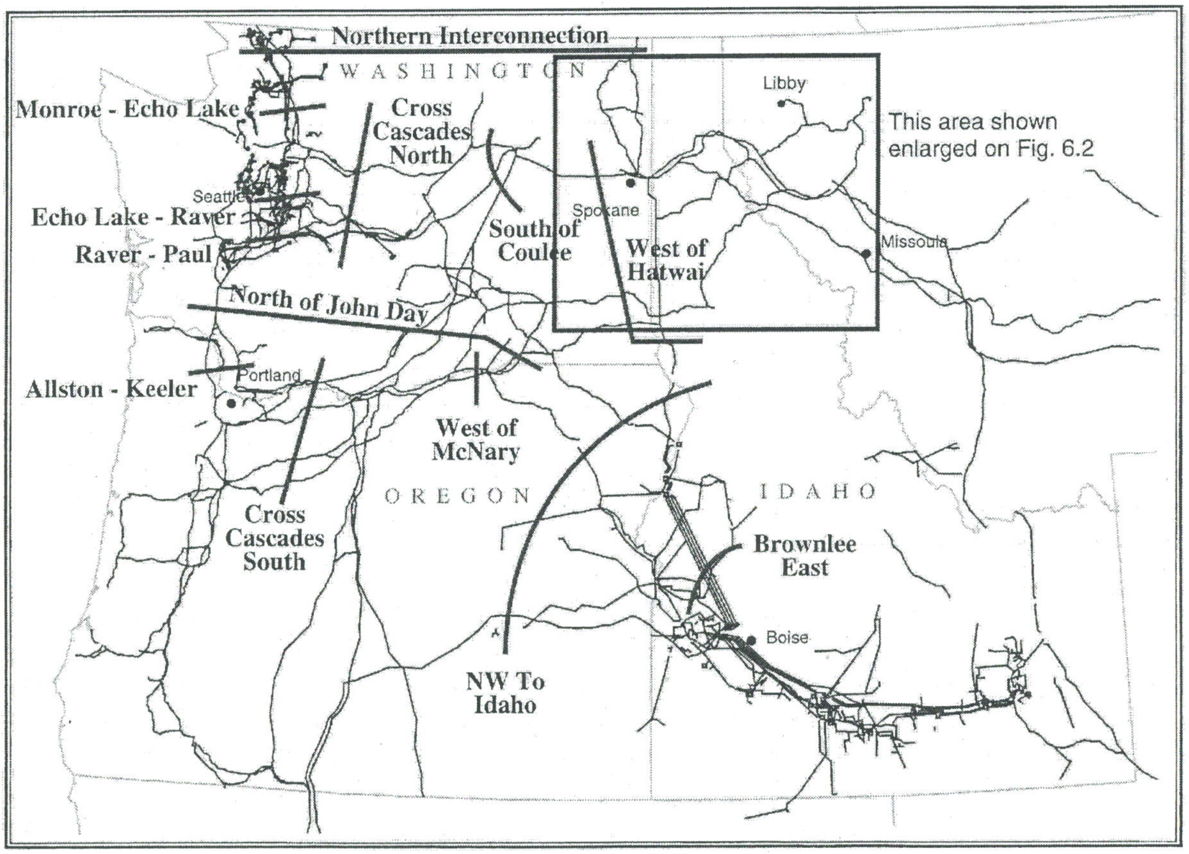
The existing and any additional turbine-generator units at Libby can only be operated to generate electricity, and hence release the flow required by the 2000 BiOp, if there is sufficient transmission line capacity and demand (load) to accommodate the output. There are currently both regional and local transmission line capacity constraints that limit the output from the existing five units in Libby powerhouse from time to time.

Regional Transmission Constraints

Portions of the Northwest transmission system were recently described as "approaching gridlock." The statement was made in a report dated August 2001 by an Infrastructure Technical Review Committee(2) composed of representatives of major generating utilities, in support of a request for additional borrowing authority for BPA. BPA operates three-quarters of the bulk transmission in the Northwest.

The report identified a series of constrained transmission paths within the Northwest. The constrained path of concern to this study is known as the West of Hatwai (WOH) cut plane in eastern Washington (see Figure 6.1). The WOH *transmission path has historically been rated at 2,800 MW, although seasonal and diurnal ambient air temperatures can reduce this capacity to about 2,000 MW. The WOH path is fully subscribed with firm obligations from generation east of the cut plane. The path has experienced congestion in the past but it has typically been managed. However, recent load reductions at the Kaiser Mead aluminum plant in Spokane, Washington, and at the Columbia Falls Aluminum Company in Kalispell, Montana, have decreased the load east of the WOH cut plane by approximately 800 MW. The energy that used to serve these loads (including generation from Hungry Horse and Libby in Montana) is now available to flow across the WOH cut plane causing increased congestion. The output from additional units at Libby would compound the congestion.*

FIGURE 6.1
Northwest Constrained Transmission Paths



The infrastructure committee's report contains details of 20 proposed projects aimed at upgrading the capacity and reliability of the transmission system in the Northwest. These projects are scheduled in three phases.

Phase 1 includes Project G9 - West of Hatwai Additions (Bell-Coulee 500 kV line, 500 kV series compensation). The project will relieve the congestion across the WOH cut plane, which constrains transmission between eastern generation facilities (including Libby) and west-side load centers within the Pacific Northwest. Project G9 includes six components with an estimated cost of $115 to $120 million. The principal component is to remove one of the existing Bell-Grand Coulee 115 kV lines (see Figure 6.2) and construct approximately 83 miles of new 500 kV line in its place.

The report indicates an energization date of 2004. Although also required to overcome existing constraints, the project of increasing transmission capacity is an essential requirement for any additional generation at Libby.

Phases 2 and 3 are addressed under the following section, Local Transmission Constraints.

Local Transmission Constraints

Three hydroelectric generating stations supply electricity to the local transmission system in western Montana in addition to Libby. These stations are

- *Hungry Horse, owned by the U.S. Bureau of Reclamation, nominal capacity 428 MW*
- *Cabinet Gorge, owned by Avista Corp., nominal capacity 231 MW*
- *Noxon Rapids, owned by Avista Corp., nominal capacity 466 MW*

Together with Libby, nominal capacity 555 MW, the four stations represent a total nominal capacity of 1,680 MW. However, the Hungry Horse and Noxon Rapids stations are operated as peaking stations and Libby is capable of sustained generation up to 605 MW when sufficient head and flow are available. Under these conditions, the total capacity of the four stations is approximately 1,835 MW. The capacity of the existing local transmission system varies depending upon the loads being served and the units that are in operation at each station, but is generally considered to be only about 1,600 MW. This capacity is 80 MW less than the total nominal capacity of the four stations and approximately 235 MW less than their maximum total output. Consequently, the existing local transmission system certainly does not have the capacity to accommodate the output from even one additional generating unit at Libby.

As indicated on Figure 6.2, a number of projects are being considered to overcome local transmission constraints.

Phases 2 and 3 of the transmission infrastructure upgrade mentioned earlier include two projects, G15 and G20, aimed at reinforcing the 230 kV system to maximize the transfer capability across the WOH cut plane and to mitigate the local problems on the subgrid in western Montana that have an adverse effect on the main grid system when hydroelectric generation in western Montana is at high levels (as indicated above).

Project G15 - West of Noxon Reinforcement - Phase I (Libby-Bonners Ferry line rebuild) would involve the rebuilding of the line between Libby and Bonners Ferry substation (60 miles of new 230 kV double circuit construction). The new line would initially be operated at 115 kV. The project is needed to relieve overload constraints during high Montana-Pacific Northwest transfers (as indicated above). The project addresses limiting outages on the existing Libby-Noxon 230 kV line and outages on the Taft-Dworshak and Taft-Bell 500 kV lines. The project would be built double circuit to provide for future load service to North Idaho and provide the flexibility to extend the 230 kV line to Bell substation near Spokane. The latest estimated cost of the project is $64.5 million, including overhead. The report indicates an energization date of fall 2005, but it is understood that agreement has yet to be reached between BPA and the other utilities involved regarding this project. The *proposed capacity of this line is not reported, but it is understood that this line alone would not accommodate the output from one or two additional units at Libby.*

Project G20 - West of Noxon Reinforcement - Phase II (Libby-Bell 230 kV line) would involve construction of 75 miles of new 230 kV line between the Sandpoint area and Bell substation to create a new Libby-Bell 230 kV line, including terminal facilities. In addition, a new 230/115 kV transformer would be added at Sand Creek substation. One side of the Libby-Bonners Ferry double circuit line (Project G15 described above) would then be operated at 230 kV. The project is needed to reinforce the North Idaho load center, solve overload constraints during high Montana-Pacific Northwest transfers, and reduce the need for generator dropping at Libby. The project addresses limiting outages on the existing Libby 230/115 kV transformer/Cabinet Gorge-Sand Creek 115 kV line, the Libby-Noxon 230 kV line, and outages on the Taft-Dworshak and Taft-Bell 500 kV lines. The latest estimated cost of the project is $61.9 million, including overhead. The report indicates an energization date of fall 2006, but it is understood that agreement has yet to be reached between BPA and the other utilities involved regarding this project. The proposed capacity of this line is not reported. Furthermore, the statement that it would "reduce," rather than eliminate, the need for generator dropping at Libby does not offer assurance that this project would provide capacity for the transmission of the output from additional units. Project G15 is also an essential precursor to this addition.

The infrastructure report also includes preliminary details of non-federal projects under consideration that may serve as alternatives to G15 and G20. Alternative A1 - Noxon-Shawnee Reinforcement, an Avista Corp. project, includes two components that Avista believes provide a less costly, more practical and less environmentally challenged solution than the G15/G20 projects, as well as a larger capacity. The two components are completion of the second Noxon-Pine Creek 230 kV line and reconductoring/rebuilding of the Pine Creek-Benewah 230 kV line. The "ballpark" estimate for this project is $40 million. (The Noxon-Shawnee Reinforcement also includes a third component, construction of the Benewah-Shawnee 230 kV line. However, this component is already in Avista's budget, and agreement has recently been reached with BPA for its construction.)

In response to inquiries during this study concerning the impacts of additional generating units at Libby, Avista has developed a variant of the Noxon-Shawnee Reinforcement project that it believes would be even more cost-effective. This would involve the construction of a 230/500 kV step-up substation at Shoshone, where the existing 230 kV Noxon-Pine Creek line crosses the Taft-Bell 500 kV line. The second Noxon-Pine Creek line in Alternative A1 would then only extend to Shoshone, and both the existing and new line would be connected via the substation to the 500 kV Taft-Bell line. The "ballpark" estimate for this alternative is $35 million.

Although not mentioned in the infrastructure upgrade report, reinforcement in the area (either the G15/G20 or Avista's projects) would also have to include a second 230 kV line between Libby and Noxon, as shown on Figure 6.2. The figure reflects the fact that prior to the construction of Libby, a single 230 kV transmission line connected Conkelley/Haskill and Noxon, passing approximately 24 miles to the southeast of Libby. The line was "cut" at that point and the two sides were connected into the Libby switchyard. The connection resulted in the addition of up to 605 MW input to the line, but with no increase in capacity. The "ballpark" estimate for the second line is $25 million.

The importance of the second Libby-Noxon line is illustrated by an incident that occurred in August 1999, when line crews found a tree threatening proximity contact with the existing Libby-Noxon 230 kV, and an outage was required to attend to the problem. Hungry Horse (which is connected to the Conkelley system) ceased generation to avoid overloading the 115 kV line out of Libby switchyard. Soon after the 230 kV line was switched out to attend to the tree, sagging and arcing on the 115 kV line required the line to be disconnected. As soon as the 115 kV line was disconnected, power oscillations began to occur between the units at Libby and the rest of the system, causing the remaining 230 kV line (to Conkelley/Haskill) to trip, resulting in the dropping of all generation at Libby. Releases at Libby decreased from 17,000 cfs to 2,000 cfs for about 45 minutes.

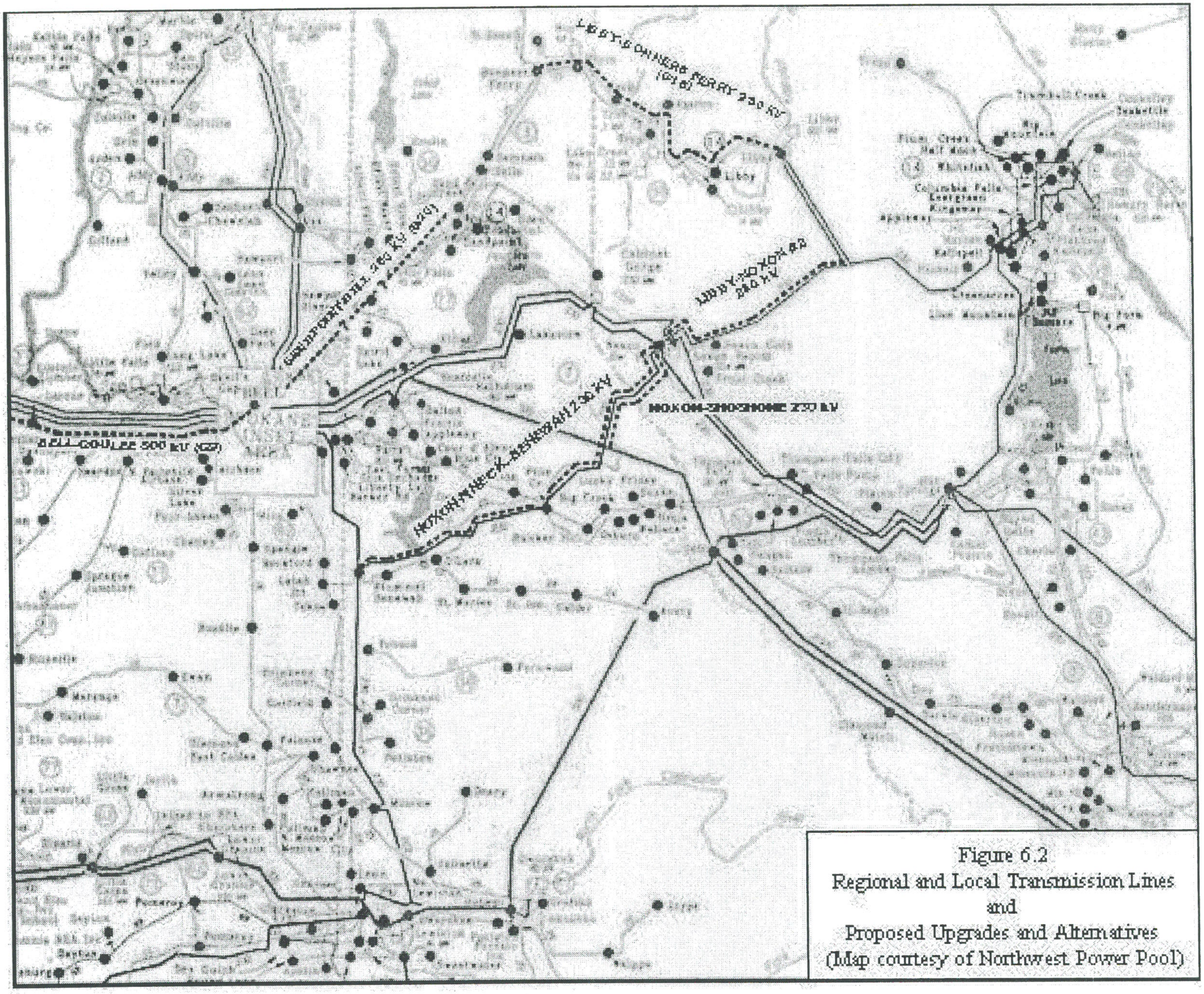


Figure 6.2
Regional and Local Transmission Lines
and
Proposed Upgrades and Alternatives
(Map courtesy of Northwest Power Pool)

In addition to the foregoing major constraints, review of the allowable amperage ratings of transmission lines published by BPA has also revealed a local constraint on one of the two short 230 kV transmission lines from Libby powerhouse to the BPA switchyard across the river. The original project one-line electrical diagrams show that it was intended that each of the two transmission lines would serve four units, Units 1 to 4 on Line 1 and Units 5 to 8 on Line 2, although ultimately Units 1 and 2 were connected to Line 1 and Units 3 to 5 were connected to Line 2. As expected, both lines have the same type of conductors, 1780 ACSR Chukar. However, the allowable amperage ratings and hence the capacity of the lines are significantly different; Line 1 being rated at less than 50 percent of the rating of Line 2 because the maximum operating temperature is restricted to 50°C, rather than 100°C. The reduced rating means that Line 1 currently does not have the capacity to accept another unit. Line 2 does appear to have the capacity to accept up to two more units (five total), unless there are capacity limitations in the switchyard, but the unbalanced division of output is not desirable. Ideally, if two units are added, Units 1 to 4 would be connected to Line 1, and Units 5, 7, and 8 would be connected to Line 2.

The Transmission Business Line of BPA advises that the restriction on Line 1 can probably be readily remedied, and has recommended an allowance of $250,000 to cover this.

Conclusion

Transmission projects totaling a minimum of between $175 and $180 million and possibly ranging as high as $266 to $271 million would need to be in place before the regional and local transmission system can accommodate the output from additional units at Libby, although these transmission projects are also required to address existing conditions.

7.0 ALTERNATIVE METHODS OF RELEASE

Because of the existing transmission constraints that will delay commissioning of one or two additional units, other means of releasing the additional flows were considered.

The spillway and/or sluices provide alternative means of releasing water from Libby Dam. However, the use of the spillway and/or sluices is the subject of a separate study (RPA 8.2.a.3), and was, therefore, excluded from the scope of this study.

The existing penstocks, spiral cases, and draft tubes also provide direct passages to release water from Libby Dam. The power intakes in the reservoir are also equipped with a selective withdrawal system to effect control of the temperature of the released water. A suggestion by a previous client on another project prompted consideration of the possibility of removing the turbine runners from the units and using the existing wicket gates to control the flow. This approach is not directly applicable at Libby because of the very high head involved. The wicket gates and the immediately adjacent internal surfaces of the turbine housings and draft tubes would be subjected to excessive flow velocities, with a high probability of severe cavitation damage. Consequently, a means had to be found to control the flow and dissipate the energy of the water that would otherwise be converted into electrical energy.

Two possibilities were considered.

- *Installing a series of multiple orifice steel baffle plates in the penstock upstream of the turbine spiral case; and*
- *Installing pressure-reducing valves in the top of the draft tube.*

A preliminary structural analysis of the baffle plates showed that the amount of stiffening required to resist the differential pressure (head loss) produced by the orifices could be prohibitively costly, due both to the amount of steel involved, and the difficulty of fabricating and installing the assemblies inside the penstocks. In addition, preliminary hydraulic calculations indicated that as many as 10 plates 20 feet in diameter would be required to produce the necessary head loss, assuming that orifice jet velocities were maintained sufficiently low to avoid cavitation and the need to fabricate the plates from stainless steel rather than mild steel. This alternative would probably allow a larger flow than the second alternative. The concept could still be pursued, but hydraulic model testing and detailed structural analysis would be required to establish whether a technically feasible design could be developed.

The second, and more likely feasible alternative, would be to install multiple-orifice, pressure-reducing valves, such as the Type 811 Polyjet valves manufactured by CMB Industries in Fresno, California, in the draft tube immediately below the turbine spiral case. The Type 811 valve is designed to operate submerged in a stilling well or tank. The valve represents proven technology, but its use in this application would be unconventional and unprecedented. The valves would be mounted below a heavily stiffened support structure seated on the existing turbine discharge ring. The turbine runner and the entire head cover and wicket gate mechanisms would be removed and a new heavily stiffened head cover would be bolted in their place. The operating stems of the Polyjet valves would extend up *through the new head cover and be equipped with packing glands. Preliminary inquiries to CMB Industries indicate that this alternative is probably feasible, but installing three valves in close proximity could introduce turbulence problems and require the use of smaller valves equipped with cylindrical shields.*

There are some significant drawbacks to this alternative, the most important being the discharge capacity. The largest valve manufactured by CMB Industries, 60-inch diameter, has a capacity of only 590 cfs. Consequently, the maximum capacity of one, three-valve installation would be only 1,770 cfs. Equipping all three available units with Polyjet valves would only achieve a maximum capacity of about 5,300 cfs (i.e., about 4,700 cfs less than called for by the 2000 BiOp). Problems with turbulence could force the use of smaller diameter valves, with a commensurate reduction in capacity.

Another potential drawback is the susceptibility to plugging of the small orifices within the valves by debris. In a conventional installation, this is typically addressed by providing a back-washing system. Such a system would further complicate the installation, but would be preferable to having to install fine screens on the penstock intakes.

Current staff would have to be trained to operate and maintain the valves, and a separate inventory of spare parts would be required.

The total cost of the three installations has not been estimated, but the supplier's budget price for nine 60-inch valves is $2.3 million. Hence, it is believed that the ultimate total cost, including developmental engineering and testing, could be in the order of $7 to $8 million.

A non-generating solution would also result in a loss of generation and the associated revenue. The loss in generation was estimated based on assumed distributions of the additional releases in May and June called for by the 2000 BiOp that included allowing for the flow ramping restrictions (limitations on rates of increase and decrease in flows) in force at Libby. The results are shown in Table 7.1. The table shows that the discharge of the additional 10,000 cfs by non-generating means would result in an estimated long-term average loss of generation in May of 32.5 MW (15 percent of the long-term average) and a loss in June of 42 MW (11 percent of the long-term average). Valued at $30 per MWh, the loss in generation would be worth approximately $1.6 million per year.

In addition, unlike the intermittent additional generation produced by the additional units, the loss in generation and associated revenue due to a non-generating alternative would be experienced in all but a few years.

TABLE 7.1
GENERATION LOSS FROM A NON-GENERATING ALTERNATIVE

YEAR	LOSS IN GENERATION (MW)												
	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	July	Annual
1929											26		2.1
1930										11	17		2.4
1931													
1932										29	72		8.4
1933										21	49		5.8
1934										71	94		13.8
1935										23	49		5.9
1936										12	24		2.9
1937										11	22		2.7
1938										26	56		6.8
1939											24		2.0
1940										11	24		2.9
1941													
1942										11	37		4.0
1943										30	48		6.5
1944													
1945										11	22		2.7
1946										52	86		11.5
1947										73	52		10.4
1948										110			9.3
1949										92	51		12.0
1950										42	49		7.6
1951										36	36		6.0
1952										38	20		4.9
1953										43	27		5.9
1954										46	34		6.7
1955										27	53		6.7
1956										27	85		9.3
1957										73	103		14.7
1958										64	42		8.9
1959										35	33		5.7
1960										36	53		7.4
1961										64	97		13.4
1962										12	81		7.7
1963										17	55		6.0
1964										27	64		7.5
1965										21	48		5.7
1966										27	47		6.1
1967										23	33		4.6
1968										11	69		6.6
1969										62	36		8.3
1970										11	23		2.8
1971										44	75		9.9
1972										90	10		8.4
1973										11	21		2.6
1974										43	52		7.9
1975										24	49		6.1
1976										51	27		6.5
1977													
1978										29	27		4.7
Average										32.5	42.0		6.2

8.0 FUNDING

The sources of funding for the capital cost and ongoing operation and maintenance costs for the means of releasing additional flows considered in this report have not been determined.

9.0 SUMMARY OF FINDINGS

The turbines for Units 6, 7, and 8 are almost completely installed, although some parts of the turbine for Unit 6 have been used to maintain operating units. The parts that could be observed are in good condition. Safety considerations due to the uncertainty of water levels within the units prevented internal inspection of the water passages, including the penstock, and the turbine runners. The internal condition is, therefore, unknown. Consequently, the cost estimates include for dismantling and refurbishment of the turbine components.

The review of the inventory records and examination of stored components and accessible storage crates in the powerhouse leads to the general conclusion that all major parts of the generators, governors, and switchgear are present.

The condition of most of the stored equipment is good, and after a cleanup would be suitable for installation. The mothballing procedures and protective measures have been successful in preserving the major equipment and almost all associated smaller parts provided by the original manufacturer. All major parts were delivered to site with a primer paint coating, or in some cases a finish coating. There are no material signs of rust or corrosion on the equipment except the generator rotor rim plates. The stacks of plates were originally stored outside the powerhouse and a significant proportion is covered with rust. The cost estimates provide for replacement of the plates.

The governor pressure tanks will have to be cleaned and painted inside and out, assembled, and pressure tested for licensing.

Bulk installation materials, such as cable, wiring, conduit, small diameter piping, and some instrumentation, would have to be supplied by the installation contractor along with other consumables.

The main power transformer T4 originally ordered for the project was used at another Corps project. A new transformer would be required if two additional units are to be completed and commissioned. The transformer would have to be transported to the site by road and the feasibility of accomplishing this without exceeding the allowable loadings of bridges on the route must be determined.

The interiors of the water passages and the turbine runner must be inspected to determine their condition and confirm the feasibility of completing and operating the units. A protocol to safely access the interior passages would first have to be established and executed. Unless severe corrosion of the water passages, particularly the penstock, is discovered, which is unlikely, it appears feasible to complete the installation and commissioning of one unit. The installation and commissioning of a second unit may also be feasible, but is subject to determination of the feasibility of transporting the necessary transformer to the site.

With the possible exception of a slight increase in efficiency, the additional units would provide no reliable economic benefit, but they would provide increased flexibility and reliability in the operations at Libby.

Before additional units can be completed and commissioned, significantly more costly upgrades to the regional and local transmission system must be completed. Without these transmission upgrades, the additional units could only serve as *replacements for the existing units; they could not be operated together with the existing units and could not, therefore, release the additional flows called for by the 2000 BiOp. The time frame for completing the transmission upgrades is uncertain, but is probably at least four years away. Consequently, it is concluded that it is not currently feasible to release the additional flows required by the 2000 BiOp by installing additional generating units.*

The use of multi-orifice, pressure-reducing valves to release additional flows without the need for additional transmission capacity may be feasible. However, this non-generating alternative would only be capable of releasing about half of the additional 10,000 cfs required by the 2000 BiOp. The remainder would, therefore, have to be spilled, which may or may not be acceptable, depending upon the downstream total dissolved gas levels that would result. In addition, although pressure-reducing valves are proven technology, their use in this application would be unprecedented. Several years of investigations and tests would, therefore, be required to confirm the feasibility, develop an appropriate design, and complete the fabrication and installation. Consequently, it is concluded that pressure-reducing valves do not currently provide a feasible alternative means of releasing the additional flows required by the 2000 BiOp.

The spillway and/or sluices provide alternative means of releasing water from Libby Dam. However, the use of the spillway and/or sluices is the subject of a separate study.

10.0 REFERENCES

1 *The Columbia River System Inside Story, Second Edition, U.S. Bureau of Reclamation, U.S. Army Corps of Engineers, Bonneville Power Administration, April 2001.*

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4 *Memorandum on Study No. 00FSH33, Bonneville Power Administration, November 16, 2000.*